STATE OF CALIFORNIA
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

In the Matter of:	)	Docket 97-DC&CR-1
	)	
Informational Proceeding to Develop Recommendations for Amending the Energy Commission's Responsibilities and Activities Related to Data Collection, Analysis, and Dissemination	)	NOTICE OF STAFF COMMENTS ON THE COMMITTEE HEARING ON 5-10-99 AND THE AD HOC INFORMATION COMMITTEE REPORT ON: PROPOSED GENERATION REPORTING REQUIREMENTS: QUARTERLY GENERATOR OUTPUT AND FUEL USE
Proposed Amendments to the Energy Commission's Regulations Pertaining to Data Collection and Disclosure of Energy Commission Records	)	

Staff Comments On
The Ad Hoc Information Committee Hearing on May 10, 1999
and
The Committee's Report On
"Proposed Generation Reporting Requirements: Quarterly Generator Output and Fuel Use"

June 7, 1999

Introduction

On May 10, 1999 the Ad Hoc Information Committee held a hearing for comments on its **Proposed Generator Reporting Requirements: Biennial Power Plant Characteristics And Quarterly Generator Output And Fuel Use** report[1]. At the end of the hearing the Committee asked for written comments on the report and issues raised. In these comments, Energy Commission staff in the Energy Information and Analysis Division address three major topics. First, we restate the Energy Commission's previously stated purpose for collection of power plant characteristics and quarterly generator output and fuel use. Second, we discuss the need for detailed plant characteristics and why statewide averages will not suffice. Third, we explain why old databases on plant characteristics are not relevant and how data filed at other agencies may be used as compliance options to satisfy generator output and fuel use reporting requirements.

Since these topics have been examined extensively during the Energy Market Information Proceeding, this document is in great part a review of the record of previously stated Energy Commission and/or Committee conclusions and staff comments.

I. What is the purpose of the information collected? What authority does the Energy Commission have to collect it?

These two questions were a recurring theme in the statements made by witnesses at the May 10, 1999, hearing. At various points during the hearing representatives of Southern California Edison (SCE), Pacific Gas & Electric (PG&E), and the Independent Energy Producers Association (IEP) all indicated that the Energy Commission had not identified the purpose for collecting generation plant characteristics and generator output and fuel use data. Witnesses further commented that the Energy Commission had not indicated why the data was relevant, what role the Energy

[1] Ad Hoc Information Committee, Docket 97-DC&CR, April 28, 1999, hereto referred to as the April 28th report.

Commission would play in the restructured market, and what jurisdictional rights the Energy Commission had in collecting the data.[2]

[2] Transcript of AD HOC INFORMATION COMMITTEE HEARING on PROPOSED GENERATOR REPORTING REQUIREMENTS hearing, Monday, May 10, 1999, (e.g., see SCE on p. 11, PG&E on p. 34, and IEP on p. 55).

I.A. Energy Commission's Stated Positions Within The Market Information Proceedings

The Energy Commission and/or the Ad Hoc Information Committee have all previously identified the purpose for collecting the information and its statutory rights to collect data. In support we offer excerpts from the **Ad Hoc Information Committee Report On The Energy Market Information Proceedings**[3], which was adopted by the full Commission at the June 24, 1998 business meeting, and the April 28th report, currently at issue. In the June 12, 1998 report, the Committee concluded, and the Commission adopted, the following findings of fact, conclusions of law, and policy conclusions.

Findings of Fact

- Restructuring of the California electricity market has fundamentally changed the nature of the electricity industry from one that was dominated by highly regulated, integrated utilities, to one that relies to a large extent on market forces and competition. The Committee finds that restructuring the electric-industry, in and of itself, does not eliminate the need for the Commission's electric industry monitoring and policy-development functions as required by statute.

- The Commission's monitoring and policy-development functions are supported by several important activities. The activities of conducting electricity system trends analysis (including demand forecasts, supply planning, development of future resource outlooks, and issues/problems identification), analyzing electricity policy and developing policy recommendations remain important to state decision-makers, consumers and market participants.

Conclusions of Law

- The Committee concludes that restructuring of the electricity industry does not change the Commission's authority to collect data necessary for electricity industry monitoring and policy development.

- The Committee concludes that there is ample authority for the Commission to move forward with rulemaking on data collection for the Commission's core energy industry monitoring and related policy-development functions under Public Resources Code Sections 25216 and 25216.5(d). There is also sufficient clarity with respect to our roles and responsibilities related to the Commission's electric industry monitoring and policy-development functions to move forward with changes, deletions, and revisions to regulation for data collection, analysis and dissemination in the rulemaking proceeding to commence this summer. The question of what specific data we will collect and from whom will be a primary focus of this rulemaking.

[3] CEC Docket 97-DC&CR-1, June 12, 1998, hereto referred to as the June 12, 1998 report.

Policy Conclusions

- The Committee concludes that the Commission should streamline its data collection activities, where possible, and pursue only the data necessary to allow the Commission to accurately project loads and adequately model the electricity system as part of its electricity monitoring and policy-development functions. The Committee will entertain new methods to obtain these data in the rulemaking.

  On the supply side, this means the Commission needs sufficient or appropriate data to allow it to characterize power plants and the electricity system including fuel use, heat rates, and other characteristics to allow system modeling. It will need system and generation data including ISO/PX prices and quantities to support analytical reports.[4]

Broader policies with respect to the Energy Commission's roles in the restructured electricity market can be found in the Strategic Plan and the most recent State Energy Plan. Moreover, the adoption of the June 12, 1998 report by the full Commission endorsed the market monitoring and policy analysis functions that the Energy Commission would perform and for which the Committee wrote its proposed generation reporting requirements.[5]

Given these conclusions, staff believes the questions of purpose and jurisdictional right to collect the data are no longer at issue, despite the apparent desire of some participants at the hearing to continue that debate. In the April 28th report the Committee emphasized:

> In its June 12, 1998 Report on the Energy Market Information Proceedings, the Committee developed findings of fact and conclusions of law with respect to its jurisdiction and authority for its information-related functions. This report was developed largely to respond to parties' questions and concerns regarding the Energy Commissions authority and jurisdiction in the restructured electricity market. At its June 24, 1998 Business Meeting, the full Energy Commission adopted the Committee's findings and conclusions dealing with the Energy Commission's jurisdiction and authority, as well as its roles and functions in the restructured electricity market.
>
> The Energy Commission concluded that its responsibilities for assessing and monitoring energy market trends and developing energy policies continue to be justified and may become more important as the competitive electricity market emerges. The fundamental public interest rationale for continued assessment and monitoring of the electricity industry are the statewide electric system impacts and environmental impacts associated with electric facilities. The addition of new power plants and transmission lines directly impacts the operation of other power plants and transmission lines in the interconnected electricity grid and involves environmental and other impacts that extend beyond the local are where

[4] Ad Hoc Information Committee, CEC Docket 97-DC&CR, June 12, 1998, pp. 5-7.
[5] Ad Hoc Information Committee, CEC Docket 97-DC&CR-1, April 28, 1999.

facilities are sited. As such, an understanding of these impacts is an essential input to developing informed State energy policies.[6]

. . . The Energy Commission concluded that electric industry restructuring does not change the Energy Commission's authority to collect data necessary to carry out its mandated functions. The Energy Commission also concluded that it has ample authority under existing mandates to collect data to support its core functions from new market participants, where appropriate.[7]

I.B. Energy Commission's Statement To The Legislative Analyst's Office

The Energy Commission has identified, for the Legislative Analyst's Office (LAO), the major electricity generation planning activities the Commission is engaged in, why these activities should continue, and the benefits these activities provide. The LAO developed several sets of questions to which various state agencies prepared responses for the Senate Budget Subcommittee 5 review of agency functions for the fiscal year 1999/2000 budget. In its February 25, 1999 memo to the LAO, the Energy Commission identified the following activities.

A. Energy System Monitoring, Evaluation and Forecasting involves: [emphasis added]

1. collecting data on key supply and demand variables such as current and historic production, resource mix, appliance stock, regional development and economic trend;
2. identifying quantitative indicators for meaningful trends
3. forecasting possible future implications of trends, and
4. identifying whether there are short- and long-term state policy concerns should the trends continue

Benefits: An integrated monitoring function provides an early alert system on whether trends are consistent or inconsistent with state policies and documents the degree to which state policies are being achieved. This basic data is not collected by any other private or governmental entity. It also supports other Energy Commission programs by providing a baseline against which to compare program performance and policy alternatives.

B. Information Dissemination [emphasis added]

1. Annual fuel mix, published in the state-mandated Power Content Label, which consumers can use as a basis for comparison with their electricity purchases, as part of administering the generation disclosure program (SB 1305. Sher, Chapter 796, Statutes of 1997).
2. Analysis, technical assistance and forecasts provided to consumer and small business groups regarding opportunities for co-ops and aggregation services so they can take advantage of the new competitive market's benefits.

[6] Ad Hoc Information Committee, CEC Docket 97-DC&CR-1, April 28, 1999, p. 1.
[7] ibid., p. 2.

3. Monthly summaries and interpretation of wholesale electricity prices and their implications for market participants. This report is regularly quoted as an authoritative source of information in major national newsletters.
4. Annual projections of seasonal electric market clearing prices. Based on requests and website downloads [over 1,000 per month], these reports are [among] the most popular Energy Commission publications.

Benefits: Market participants need objective, credible information to function; such information reduces uncertainty and allows participants to evaluate their potential risks and rewards. Making such information publicly available has the potential to decrease costs to market entrants. Project developers and financial institutions who follow our wholesale and market clearing price report receive an unbiased baseline to use in benchmarking their own analysis. . . Policy makers and market participants will have access to historical and forecasted information about energy options, facts, trends and issues, via the CEC website, the California Statistical Abstract and the Governor's Economic Report.

C. Policy Development [emphasis added]

- **How does a potential or proposed change affect the energy market?** The change can be new legislation, new energy or environmental policies, new governing rules, new subsidies, revised market structures, or changes in market structures. For example: what is a plausible range of scenarios for the mid-term market outlook, and are there positive or troubling trends evident within these potential developments? What is the effect of changes in fuel prices, air quality emission rule changes, new ISO tariffs and hydro availability on the mid-term market?

- **How will the energy market affect the environment?** What effects on fuel resources and the environment will various policies or market developments have? What are the economic and environmental effects of the California market structure on the power generation industries in other Western states, and are there steps we should take to deal with the concerns of policy-makers in other Western states?

- **Can we explain something we observed happening in the market?** Often something is observed that can't at once be explained. Systematic review can illuminate the causes of a phenomenon, such as whether a price spike is a normal market variation, an abuse of market power, an anomaly, a temporary glitch in market rules, or a foreshadowing of a long-term change in market price.

Benefits to decision-makers, market participants and consumers: Government will continue to be a partner in creating and maintaining the electricity market, because:

- the framework which defines the market's boundaries and scope is established by law, regulations and protocols.
- private business is not responsible for safeguarding the public interest.

Benefits to other Commission programs: Electricity financial and economic analyses provide Commission staff with the tools to analyze the cost-effectiveness of energy efficiency measures (CBEE and Building and Appliance Standards) and emerging generation technologies (AB 1890's Renewables and PIER mandates).

Benefits to other state agencies: We provide analysis to the Legislature, Air Resources Board, the Board of Equalization, and the Public Utilities Commission. State and local governments use our expertise on electricity and fuel markets to keep from overreacting to transitory events or from being misled by incomplete or inaccurate information. The Commission provides energy-related expertise, information and analysis to assist state and local

> environmental regulators and policy makers, permitting environmental and energy policies to be mutually reinforcing, rather than unnecessarily conflicting.[8]

The Energy Commission has identified, for the Legislative Analyst's Office (LAO), the major electricity transmission planning activities the Commission is engaged in, why these activities should continue, and the benefits these activities provide. The following are excerpts for the Energy Commission's March 3, 1999 memo to the LAO.

> The Commission performs independent and objective analyses of integrated generation, demand, energy efficiency and transmission for the western interconnected region. . . The Warren-Alquist Act directs the Commission to evaluate the trends in energy supply and demand, statewide demographics and economic factors that would affect the demand and supply of energy; and the social, economic and environmental implications of these trends. To address this requirement, the Commission has ongoing activities to monitor the electricity industry, assess trends in supply and demand and develop state energy policy. The Commission's ability to independently analyze transmission issues is a critical element of our electricity system assessment function. [9]

I.C. Energy Commission Staff Examples of Analyses

Some participants may argue that before data collection can begin each and every single analysis that the Energy Commission might do needs to be identified and described. While it is staff's intention to describe current and potential projects throughout these comments, we believe that a complete enumeration of future analyses is not necessary or feasible. Such an enumeration would be analogous to knowing in advance that data collected under the Petroleum Industry Information Reporting Act (PIIRA), established in the 1980s, would be used to analyze and make policy recommendations in regards to the gasoline additive MTBE in 1999.

Staff has already made a thorough enumeration of analyses in a previous reports including, **The California Energy Commission's Electricity Supply-Side Policy, Information, Program And Regulation Activities Which May Generate Future Data Collections**[10]. As a recap of

[8] California Energy Commission memorandum to Mr. Gerald Beavers, Legislative Analyst's Office, **Material For Energy Commission Generation Planning Hearing**, February 25, 1999, pp. 1-4.
[9] California Energy Commission memorandum to Jerry Beavers, Legislative Analyst's Office, **Material For Energy Commission Transmission Hearing**, March 4, 1999, pp. 1-2.
[10] CEC Docket 97-DC&CR-1, December 1, 1997.

that report we provide a selected list of analyses that the Energy Commission will engage in as a result of its Strategic Plan and various Legislative mandates in Table 1.

TABLE 1
ENERGY COMMISSION GENERATION ANALYSES AND ROLES[11]

Role	Analysis	Why These Are Roles for the Energy Commission
Policy Recommendations	Facilitate development of the electricity market during the transition period	In AB 1890, the Legislature set forth a state policy to support restructuring of the electricity industry in order to provide benefits to California. It is thus incumbent that state agencies involved with electricity policy and electricity programs assist the restructuring process.
Market Monitoring	Study the performance of the PX-ISO process, market clearing price and various bidding options	. . . the Legislature has clearly identified reliability as a paramount issue of state interest in that AB 1890 departed from previous CPUC policy decisions to flag the need for system reliability. If the market system which has been established does not provide reliable power or provides it at an unacceptably high cost, the Legislature will want prompt notification and identification of potential remedies. While the ISO is concentrating on the near- and mid-term provision of reliable service, it is not a policy of oversight agency. The Energy Commission can provide forecast outlooks, screen options and examine the roles of multiple market participants. We can promote innovative solutions, match cost and benefits, and provide an objective assessment of proposals.
	Demonstrate the value of demand side bidding as a market-based mechanism.	
	Examine what other services and products become part of the supply-side products offered in the market.	
	Assess the evolving role of municipal utilities vis a vis the ISO	
	Provide recommendations to the ISO and PX on market power monitoring, assessment and mitigation.	
Data Dissemination	Provide future trend assessments of electrical energy market clearing prices	The Energy Commission's role is to provide a public price outlook which includes both cost-basis and bidding behavior. These will serve as a benchmark by which to compare private assessments, as a policy-planning tool for State energy programs, as an input for State business outlooks, as a source of objective information to consumers, and as an analytic tool for an independent assessment of the market.
Data Dissemination	Evaluate the net benefits of retiring generation and the construction of new generation in-state and out-of-state	The Energy Commission is interested in plant retirements and new construction for many reasons: whether the market is sending efficient signals, the impact on emissions from generating stations, the public benefits of use of existing transmission lines and substations in highly urbanized area, the potential market for new technologies, the potential for new siting cases, the inter-connection of the western region, and whether costs and benefits are correctly aligned.
Market Monitoring	Identify key trends and uncertainties and assess how they might affect the emerging electricity market	Identifying emerging trends, uncertainties, and potential issues is a fundamental role set forth in the Strategic Plan.
Policy Recommendations	Inform and collaborate with other Western states about the operation and effectiveness of the new California market as it affects out-of-state economic and environmental issues	Any new policy involves inter-state issues which are best worked out through cooperative discussions.
Policy Recommendations	Support California Air Resources Board programs through conducting generation emissions studies for ARB policies which affect use of electricity versus other fuel sources.	The California Air Resources Board (CARB) relies on the Energy Commission to provide technical input into its rule-makings.
Data Dissemination	Provide accurate information on current and historical electricity resource mix and fuel dependency	SB 1305 establishes a program under which entities offering electric services discloses accurate, reliable and simple-to-understand information on the generation attributes of the electricity they proposed to sell. Consumers need an objective benchmark to compare what they are being offered to what they would get without product discrimination. By law, the Energy Commission is required to provided that benchmark.

[11] Energy Commission Staff, **The California Energy Commission's Electricity Supply-Side Policy, Information, Program And Regulation Activities Which May Generate Future Data Collections**, CEC Docket 97-DC&CR-1, December 1, 1997.

II. Why do we need specific characteristic on plant attributes? Why don't we simply use statewide averages?

Participants at the workshop questioned the need for specific plant attributes such as heat rates, fixed and variable O&M, fuel cost data, and emission factors, and they wanted to know why statewide averages of these attributes could not be used.[12] These issues have been addressed in the record. In its April 28th report on proposed generator reporting requirements, the Committee states[13]:

> Parties to the proceeding identified six variables as being the most commercially sensitive data. Within the operating-data category the variables are heat rate by block, equivalent forced outage rate, maintenance schedule and/or outage rate, and ramp rate. In addition, variable and fixed O&M components were identified as highly sensitive. Generators have these data and report them to the ISO and the PX. Therefore, the Committee does not consider the issue to be about burdensome reporting requirements, but rather about confidentiality.
>
> In response to this concern the Committee investigated using estimates for these variables to avoid the dispute over disclosure altogether. We asked Energy Commission staff to use its system simulation model to test the feasibility of using estimates for these sensitive variables. Staff did this by selecting block heat rates as its test variable and developed two sensitivity case runs of the model.[14] Heat rates were varied up and down by ten percent and the results were compared with the base-case results.
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> The test results showed that, for general statewide system assessments, using estimates is sufficient. There were relatively little differential impacts among power plants resulting from the group changes in heat rates. However, for individual power plants, using estimates has a major affect on the results. A ten percent increase or decrease in heat rate can mean greater that 60 percent change in the operating of that plant compared to the base-case. This change in operation greatly effects the results of regional or zonal analyses.
>
> **This test lead the Committee to conclude that if the Energy Commission was only concerned with statewide assessments, estimated values would be adequate. However, to accurately analyze regional, zonal or location-specific impacts, facility-specific data is needed.** [emphasis added] Since the Energy Commission performs these more detailed types of analyses, facility-specific values are necessary, but only for power plants greater than 50 MW.
>
> The Committee believes that such studies are part of the energy system assessment capabilities that we should possess and apply to specific issues that arise in policy assessment, energy facilities licensing proceedings, and in cooperative endeavors with the ISO, the PX and other agencies. Examples of these analyses include: assessing air quality impacts and benefits; investigating the effectiveness of the targeted use of energy

[12] Transcript, May 10, 1999 (e.g., see PG&E on pp. 41-47, and IEP on p. 59)
[13] Ad Hoc Information Committee, CEC Docket 97-DC&CR, April 28, 1999, pp. 18-19.
[14] Memo from Joel B. Klein, "Data Gathering for Power Plant Characteristics", October 16, 1998 and Memo from Richard Grix, "Modeling the Effects of Changes in Heat Rates on Generation", October 15, 1998. p,131, Placed in CEC Docket 97-DC&CR, March 17, 1999.

> efficiency to mitigate locational air quality problems; and assessing the impacts of distributed generation targeted to defer regional distribution system or transmission system upgrades.

II.A. Power Plant Specific Heat Rates Are Needed for Sub-regional Analyses

Using heat rates as an example, the biggest problem with using a statewide average is that it eliminates the ability of the Commission to perform analyses at sub-regions of the State. Moreover, average heat rates by facility type still do not provide the level of detail needed to model sub-regions accurately because heat rates move up and down by facility and by generation level at specific facilities depending on the level of maintenance. For example the committee notes:

> . . . test results showed that, for general statewide system assessments, using estimates is sufficient. . . However, for individual power plants, using estimates has a major affect on results. A ten percent increase or decrease in heat rate can mean greater than 60 percent change in the operation of that plant compared to the base case. This change in operation greatly effects the results of regional or zonal analyses.
>
> . . . if the Energy Commission was only concerned with statewide assessments, estimated values would be adequate. However, to accurately analyze regional, zonal or location-specific impacts, facility-specific values are necessary, buy only for power plants greater than 50 MW.
>
> The Committee believes that such studies are part of the energy system assessment capabilities that we should possess and apply to specific issues that arise in policy assessment, energy facilities licensing proceedings, and in cooperative endeavors with the ISO, the PX and other agencies. Examples of these analyses include: assessing air quality impacts and benefits; investigating the effectiveness of the targeted use of energy efficiency to mitigate locational air quality problems; and assessing the impacts of distributed generation targeted to defer regional distribution system or transmission system upgrades.[15]

Heat rates not only vary based on the degree of deterioration and refurbishment, they also vary based on geographic location. Even in the case of a new unit, where we are able to get the heat rate curve from the manufacturer, the heat rate could vary depending on the environment it is placed in. The same unit will be more efficient in a cold environment than a warm one. The same unit will be more efficient if it is properly operated and maintained than a unit that receives less attention.[16] Such variation in heat rates across facilities, geographic location, and scheduled

[15] The Ad Hoc Information Committee, CEC Docket 97-DC&CR, April 28, 1999, p. 19.
[16] ibid., p. 3.

maintenance is magnified by a factor equal to the number of existing units across the State. Staff knows of no way that we could accurately guess these variations in heat rates. We would never know where the facility is in its cycle of deterioration and refurbishment or the effect of environment on the units' heat rates. Futhermore,

> Any modeling results produced under these circumstances will always be subject to successful challenge whether the results are valid or not. No matter how sophisticated or thorough our efforts are in developing this data, it will remain unconvincing – even to the modelers themselves.
>
> This is perhaps made clearest with a simple illustration. At any time during a hearing or workshop, a power plant owner – or representative – can successfully challenge the model results with a simple questions such as: "What do you have for my heat rate?" When we respond, [we used an estimated heat rate], they need only say: "That's completely wrong, [I do not operate my facility using these values]." Since we [do] not have their actual heat rate to challenge that contention, they have invalidated our results – and we have given them the necessary mechanism.[17]

II.B. Need For Operation and Maintenance Costs

In order to project seasonal electric market clearing prices, an information dissemination project the Energy Commission officially acknowledged[18], operation and maintenance (O&M) costs are needed data elements. Variable O&M costs enter into the dispatch decision (i.e., which block of power to use next), along with fuel costs (i.e., heat rate times fuel price). Fixed O&M costs are considered by many not to be part of the dispatch decision, but it can be argued that they play a role in forecasting market-clearing prices. O&M costs are used indirectly to determine bidding behavior. If bidding is estimated based solely on the variable costs and many units fail to attract sufficient revenue to survive in the market, staff must reconsider the bidding strategy knowing that somehow there has to be sufficient revenue in the market to sustain it. Yes, some units will fail in the market. But, the failure of too many units is not realistic. The market must somehow, between energy payments, RMR contract and ancillary service payments provide sufficient revenue to sustain the market. Accordingly, both the variable and fixed O&M are important to modeling.

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[17] ibid., p. 4.

[18] California Energy Commission memorandum to Mr. Gerald Beavers, Legislative Analyst's Office, **Material For Energy Commission Generation Planning Hearing**, February 25, 1999, p. 2.

II.C. Need For Fuel Cost Data

In addition to block heat rates and operation and maintenance (O&M) costs, fuel price data is also needed to estimate costs based dispatch decision (i.e., which block of power to use next). Natural gas prices vary due to supply source and transport costs, which in turn creates cost differences at geographically separate sites. Use of an average price for natural gas will diminish staff's ability to identify cost-based dispatch decisions. This means we cannot reliably predict which power plants will operate, thus reducing the value of estimated market clearing prices for regional analyses, air quality emissions for locational specific analyses, grid flows for transmission congestion analyses, etc.

II.D. Detailed, Accurate Models Facilitates Energy Commission's Market Monitoring and Information Dissemination

Energy Commission staff is now modeling the restructured electricity marketplace in order to understand the causes of the observable market results. The ability to model and understand the causes of observable market results will provide the source data for policy recommendations that lead to: (1) the State's citizens and businesses receiving their portion of the economic benefits of restructuring; (2) the new market structure providing competitive, low-cost and reliable electric service; (3) customers in the new market structure having sufficient information and protections; and (4) preservation of California's commitment to developing diverse, environmentally sensitive electricity resources.

Staff have moved away from the control area modeling of the past in order to portray the marketplace. But to do this staff must have accurate unit specific data. Use of statewide average input data across units will diminish staff's ability to model the effects of cost differences in running various generation units, and consequently our ability to distinguish which units are running. Inability to distinguish which units that are running, and where,

will lead to erroneous results in a variety of studies, thus reducing the accuracy of the data relied upon in the aforementioned policy recommendations. Some examples include:

> Emission Studies – Since many of the gas-fired units [would] have comparable [estimated averaged] heat rates, errors in [estimating] those heat rates will make one unit in the model run when another really should be running. Air basin emission will erroneously shift from one basin to another. In the extreme case, a basin will appear to be [in] attainment when it is not, or appear not to be in attainment when it is. This will inhibit our ability to provide generation forecasting expertise to the ARB (e.g., for EV studies), air quality districts (e.g., rulemaking, planning), CBEE (e.g., avoided externalities of DSM) and the Renewables Committee (e.g., avoided externalities of renewable subsidies).
>
> Transmission Congestion – Since we really don't know which unit should be generating at any particular time [due to the use of average heat rates], we can have apparent congestion when these is none or show no congestion when there really is some.
>
> Reliability – In turn, if a unit is really available during certain hours when the model shows it unavailable due to congestion, we misstate the reliability of the system.[19]

Having heat rates by block, unit specific fixed and variable O&M costs, and geographically separable fuel prices, staff will be able to accurately model cost-based based dispatch. With this data staff will be able to provide accurate information to policy markers as to whether or not the new markets is delivering competitive, low-cost and reliable electric service. Cost-based dispatch studies are used as a benchmark for estimating the degree of market power being exercised by various facilities.[20]

II.D. Need For Emission Factors

Power plant owners monitor their plants' emissions for both internal operating and air quality regulatory purposes. Power plants undergo initial and annual source testing and may have continuous emissions monitoring (CEM) equipment installed as well. These testing and monitoring activities are sources of the plant owner's emissions data.

The proposed generator reporting requirements for air emissions factors for power plants greater than 50 MW are separated into two types—those that do not need to match capacity block heat

[19] ibid., p. 4.

rate data (SO_x, ROG, PM10/2.5, CO_2, and air toxics) and those that do (NO_x and CO). Annual average emission factors (in #/mbtu) are sufficient for the former group, using standard methods. Heat-rate linked emission factors are required for the latter group, using a CARB-certified methodology for estimation which uses CEM or other necessary data. Since the main purpose of requiring emission factor operating data is for forward-looking system simulation studies, the reported emission factors should reflect emission controls planned for the units in the short- to mid-term.

[20] Power Conference, March 1999, Severin Borenstein paper.

III. Why not use existing data? Why not use data from other sources?

Participants at the May 10, 1999 hearing expressed their opinion that the data being requested, especially on plant characteristics, was available from other sources and that it would be a simple task for staff to collect and utilize such information.[21] As with other issues raised at the hearing, staff's response will make use of previously documented statements and decisions by the Committee. We must first emphasize three points. First, the reporting entity has the obligation to report required data to the Energy Commission. Second, the reporting entity may choose among alternative compliance options to satisfy the obligation. Third, a distinction must be made between historical generator output and fuel use data and power plant characteristic data. The historical generator output and fuel use data record what has happened; whereas, power plant characteristic are data that the power plant operators/owners would use in their own near-term planning.

III.A. Streamlined Data Requirements

Staff believes the Committee streamlined the data requirements so that when a reporting entity develops a database for its own use, or meeting reporting requirements of the EIA, PX, ISO and other agencies, these data could easily and at minimal incremental costs meet the reporting requirements of the Energy Commission. When applicable, copies of the EIA, PX, ISO and other agencies' forms could be submitted as compliance option. Use of a compliance option, however, must result in reporting of the required data within the timeframe and frequency required by Energy Commission regulations. Use of a compliance option must not result in alternative sets of data. Use of a compliance option does not require Energy Commission staff to get the data from a third party. The data must be submitted by the generator's reporting entity to the Energy Commission. And, if the agency for which the compliance option was based stops requiring the data, the reporting entity is still obligated to submit the data and must shift to a different compliance option or use the Energy Commission's default option.

[21] Transcript, May 10, 1999 (e.g., see PG&E on pp. 35, and IEP on p. 56)

Staff's interpretation of the compliance options can be referenced to two specific Committee statements in the April 28th report. First, the Committee states, ". . . this submission can, in most cases, be a photocopy of forms . . . filed with EIA."[22] Second, "The Committee notes that in providing a compliance option that entails the filing of EIA forms in lieu of Energy Commission forms, the frequency of filing must at least match the Committee's proposed requirements."[23]

III.B. Inefficient Data Collection

Staff 's collecting data from various agencies, if the appropriate data did exist and could be retrieved on a time schedule useful for Energy Commission purposes, would be inefficient for both the Energy Commission and generators. It is much simpler, and probably collectively less expensive, for the entity with a reporting requirement obligation to EIA or some other agency to simply send a photocopy to the Energy Commission. If staff tried to get the information for the other agency and it is confidential data, the agency might need the individual permission of the generator to release the data. This would entail another round of paperwork.

III.C. Default Reporting Mechanism and Compliance Options

Given the level of confusion about reporting requirement and compliance options at the May 10, 1999 hearing, staff offers a set of tables that we have prepared to provide our understanding of the generator output and fuel use reporting requirement and compliance options for power plants 1 MW or greater. For plants less than 1 MW there are no reporting requirements for the generator; information on these generators would come from a utility- provided universe of power plants.[24] The Committee's proposal would:

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[22] Ad Hoc Information Committee, CEC Docket 97-DC&CR-1, April 28, 1999, p. 11.
[23] ibid., p. 21.
[24] Ad Hoc Information Committee, **Clarification Of Questions Raised At May 10, 1999 Ad Hoc Information Committee Hearing On Proposed Generator Data Requirements**, Docket 97-DC&CR.

> . . . direct utilities to submit an electronic database of all power plants interconnected to their distribution system, regardless of size ownership, or power sales arrangements. The Energy Commission would use the information to estimate electricity production and fuel use in the aggregate by power plants less than 1 MW, and as a listing of the universe of all power plants.[25]

The universe of all power plants would provide the Energy Commission with the owners' names, addresses, telephone numbers, and installed generator nameplate capacity in order to insure compliance with all regulations.[26] Staff could compare submitted data for reporting entities to the universe of all power plants to identify non-compliance and use the nameplate capacity as one of the ways to validate submittals by reporting entities for generators greater than or equal to 1 MW. The utility distribution companies already collect and provide this data to EIA via Form 867. Therefore, the incremental cost in providing this universal database to the Energy Commission would be negligible. All non-disclosable data would be kept be kept confidential according to Energy Commission regulations.

At the May 10, 1999 hearing utilities expressed concerns about data confidentiality for interconnected generation of less than 1 MW. There are options that could alleviate this concern, for example utilities could:

1) aggregate the installed connect capacity by technology type and zip code prior to providing the data; or,

2) strip the names and address from the database.

Obviously the Committee's approach would not result in confidentiality breaches because the non-disclosable data would be kept confidential as provided under Energy Commission's data regulations.

III.C.1 Plant Characteristics

[25] Ad Hoc Information Committee, Docket 97-DC&CR, April 28, 1999, Appendix F, p. F-1.
[26] Insuring compliance of all generators was a stated concern of SCE at May 10, 1999 hearing (e.g., see Transcript pp. 21-22).

For plant characteristics, the primary method of compliance would be to have staff develop a database on power plant characteristics that would be updated by power plant owners every two years. Generators would be required to update a graduated set of data elements for changes due to past or planned refurbishments, degradation of equipment, operational changes, etc. The updated data elements should reflect all known factors the plant operator is using for its own planning purposes and attesting to in other regulated reporting venues. There are no single alternative compliance options. Most of the data, however, are collected for EIA on Form 412, Form 860A, Form 860B, and Form 767.

Emission factors augment plant characteristics for generators 50 MW or greater. As with other operating characteristics, the primary method of compliance would be to have staff develop the database elements that would be updated by power plant owners every two years, especially the heat rate linked emission factors. Alternate compliance options are available for emission factors not linked to heat rate blocks. The plant owner can file a copy of initial or annual source test data with the required information (SO_x, ROG, PM10/2.5, CO_2), or file the required emission factors using AP-42 or engineering computations (SO_x, ROG, PM10/2.5, CO_2), or file a copy of EPA Acid Rain filings (SO_x), or file a copy of source testing used to develop Health & Safety Code quadrennial toxic inventories (air toxics).

III.C.2 Generator Output and Fuel Use Data

This section describes staff's understanding of the historical generator output and fuel use data requirements and the EIA and FERC compliance options for each of the graduated generator classes. EIA forms, and when needed FERC forms, are not the entire universe of compliance options, but they appear to be the best candidates. If a reporting entity is filing the same data with the ISO, PX, or another agency, it could file a copy of that form as a compliance option. For another agency's filing requirement to be an acceptable compliance option for the Energy Commission, it must: (1) fully meets the reporting requirements of the Energy Commission, and (2) be submitted on or before the Energy Commission's due date.

Although the Committee has identified compliance options for historical generator output and fuel use data, staff believes that the most cost-effective way to meet the data requirements will be for the reporting entity to use its existing databases to populate the fields of the Energy Commission's default reporting mechanisms. As noted earlier, these databases will be maintained to meet requirements of the EIA, PX, ISO and other agencies. The default reporting mechanism will be a modified combination of QFER Forms 11 & 12.

Submission of the data on or before Energy Commission due date is required to meet mandated reports and analyses. For example, Senate Bill 1305 requires the Energy Commission to produce the Net System Power Calculation by April 15 of each year. If Form 412 was used as a compliance option but filed on April 30, EIA's filing deadline, instead of February 15, the Energy Commission current QFER deadline, the data could not be used to produce this report.

Generators Greater Than Or Equal To 1 MW and Less Than 10 MW

Table 2 provides staff's understanding of generator production and fuel-use reporting requirements and compliance options of generators 1 MW or greater and less than 10 MW. The Energy Commission's reporting mechanisms would be a combination of interim QFER Form 11 and 12, renamed to apply to both utility and non-utility power plants. The modified form would include a place to record sales by SIC code and also a place to record sales to the PX, ISO, (scheduling coordinators other than the PX), and to electricity marketers (other than scheduling coordinators).

TABLE 2
GENERATOR PRODUCTION AND FUEL-USE REPORTING REQUIREMENTS
Facilities Greater Than Or Equal To 1 MW and Less Than 10 MW

Reporting Requirements						Compliance Options		
Description of Data	**Data Unit**	**Reporting Period**	**Reporting Frequency**	**Date Data Due**	**CEC Modified Form**	**Municipal-Owned Generator**	**IOU-Owned Generator**	**Non-Utility Generator**
SIC Code For Facility		Annual	Annual	Feb 15	Combination of QFER Forms 11 & 12, used by all.	EIA Forms Assume NAICS Code 22	EIA Forms Assume NAICS Code 22	EIA Form 860B Requires NAICS Code
Net Generation	By Unit	Annual	Annual	Feb 15	Combination of QFER Forms 11 & 12, used by all.	Form 412 or 759	Form 759	Form 860B, formerly 867
Capacity at System Annual Peak Demand	By Unit	Annual	Annual	Feb 15	Combination of QFER Forms 11 & 12, used by all.	-------None------	-------None------	-------None-----
Fuel Use By Type	By Unit	Annual	Annual	Feb 15	Combination of QFER Forms 11 & 12, used by all.	Form 412 or 759	Form 759	Form 860B, formerly 867
Sales To Others	By SIC Code and Wholesaler	Annual	Annual	Feb 15	Combination of QFER Forms 11 & 12, used by all.	-------None------	-------None------	-------None-----

Municipal utilities could send a copy of EIA Form 412. EIA Form 412 is submitted either on a financial reporting year or a calendar year basis. Municipal utilities that file with EIA on a non-calendar year basis would be required to fill out the appropriate pages of Form 412 on a calendar year basis. Energy Commission compliance would require copies of these forms to be submitted on or before February 15, even though EIA requires calendar year Form 412 to be submitted on or before April 30. The municipal utility would also be responsible for removing superfluous information from the form, if desired, insuring that all required data elements are part of Form 412, and submitting the data to the Energy Commission even if EIA were to stop requiring the data.

Investor Owned Utilities could send a copy of EIA Form 759. Since EIA Form 759 is submitted monthly to EIA the reporting entities should have no problem sending copies of the monthly forms to the Energy Commission on or before February 15. "On EIA Form 759 federal regulation provide that data reported on 'stocks end of month' is confidential. For data treated as confidential by EIA, the Committee notes these data [not required by the Energy Commission] could be masked (if paper filings) or deleted (if electronic) when submitted to the Energy

Commission."[27] The utility would be responsible for (1) removing superfluous information from the form, if desired, (2) insuring that all required data elements are part of Form 412, and (3) submitting the data even if EIA were to stop requiring it.

Non-utility generators could send a copy of EIA Form 860B. Energy Commission compliance would require copies of these forms to be submitted on or before February 15, even though EIA requires Form 860B to be submitted on or before April 30. The non-utility generator would be responsible for removing superfluous information from the form, insuring that all required data elements are part of Form 860B, and submitting the data even if EIA were to stop requiring the data.

All non-disclosable data would be kept confidential according to Energy Commission regulations.

Generators Greater Than Or Equal To 10 MW and Less Than 50 MW

Table 3 provides staff's understanding of generator production and fuel-use reporting requirements and compliance options of generators 10 MW or greater and less than 50 MW. The Energy Commission's reporting mechanism would be a combination of interim QFER Form 11 and 12, renamed to apply to both utility and non-utility power plants. The modified form would include a place to record sales by SIC code and also a place to record sales to the PX, ISO, scheduling coordinators (other than the PX), and to electricity marketers (other than scheduling coordinators).

TABLE 3
GENERATOR PRODUCTION AND FUEL-USE REPORTING REQUIREMENTS
Facilities Greater Than Or Equal To 10 MW and Less Than 50 MW

[27] Ad Hoc Information Committee, CEC Docket 97-DC&CR, April 28, 1999, p. 23.

Reporting Requirements						EIA Compliance Options		
Description of Data	**Data Unit**	**Reporting Period**	**Reporting Frequency**	**Data Due Dates**	**CEC Modified Form**	**Municipal-Owned Generator**	**IOU-Owned Generator**	**Non-Utility Generator**
SIC Code For Facility	By Unit	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	EIA Forms Assume NAICS Code 22	EIA Forms Assume NAICS Code 22	EIA Form 860B, formerly 867, requires NAICS Code
Net Generation	By Unit	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	EIA Form 759 or EIA Form 767	EIA Form 759 or EIA Form 767	EIA Form 860B, formerly 867, or EIA Form 900
Capacity at Peak Demand	By Unit	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	-------None------	-------None------	-------None------
Sales to Others	By SIC Code and Wholesaler	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	-------None------	-------None------	-------None------
Fuel Use by Type	By Unit	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	EIA Form 759 or EIA Form 767	EIA Form 759 or EIA Form 767	EIA Form 860B, formerly 867

Utilities could send copies of EIA Form 759 for the net generation and fuel use data. EIA requires this form to be submitted monthly by the 10th working day of the month following the reporting month. The three monthly submissions could be sent to the Energy Commission each quarter, or they could be sent individually each month when sent to EIA.

Non-utilities could send copies of EIA Form 900 for the net generation data. EIA requires this form to be submitted monthly within 30 days of the end of the reporting month.

Non-utilities could send copies of EIA Form 860B for the fuel use data. EIA requires this form to be submitted annually by April 30th of the following year. Since this is an annual form, the reporting entity would be require to fill in the data on a monthly basis using Form 860B and submit the three monthly forms quarterly.

Utilities and non-utilities would be responsible for (1) removing superfluous information from the form, if desired, (2) insuring that all required data elements are part of a compliance option,

and (3) submitting the data even if in the absence of a compliance option. All non-disclosable data would be kept confidential according to Energy Commission regulations.

Generators 50 MW and Greater

Table 4 provides staff's understanding of generator production and fuel-use reporting requirements and compliance options of generators 50 MW or greater. The Energy Commission's reporting mechanism would be a combination of interim QFER Form 11 and 12, renamed to apply to both utility and non-utility power plants. The modified form would include a place to record sales by SIC code and also a place to record sales to the PX, ISO, scheduling coordinators (other than the PX), and to electricity marketers (other than scheduling coordinators). A row would also be added for reporting of monthly fuel costs.

TABLE 4
GENERATOR PRODUCTION AND FUEL-USE REPORTING REQUIREMENTS
Facilities 50 MW and Greater

Reporting Requirements						Compliance Options	
Description of Data	**Data Unit**	**Reporting Period**	**Reporting Frequency**	**Data Due Dates**	**CEC Modified Form**	**Utility-Owned Generator**	**Non-Utility Generator**
SIC Code For Facility	By Unit	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	EIA Forms Assume NAICS Code 22	EIA Form 860B, formerly 867, requires NAICS Code
Net Generation	By Unit	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	EIA Form 759 or EIA Form 767	EIA Form 860B, formerly 867, or EIA Form 900
Capacity at Peak Demand	By Unit	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	-------None------	-------None------
Sales to Others	By SIC Code and Wholesaler	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	-------None------	-------None------
Fuel Use by Type	By Unit	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	EIA Form 759 or EIA Form 767	EIA Form 860B, formerly 867
Monthly Fuel Cost by Type	By Unit	Monthly	Quarterly	Feb. 15 May 15 Aug. 15 Nov. 15	Combination of QFER Forms 11 & 12, used by all.	FERC Form 423	-------None------

Utilities could send copies of EIA Form 759 for the net generation and fuel use data. EIA requires this form to be submitted monthly by the 10th working day of the month following the reporting month. The three monthly submissions could be sent to the Energy Commission each quarter, or they could be sent individually each month when sent to EIA.

Utilities could send copies of FERC Form 423 for the fuel cost data. FERC requires Form 423 to be submitted monthly no later than 45 days after the end of the report month. The three monthly submissions could be sent to the Energy Commission each quarter, or they could be sent individually each month when sent to FERC.

Non-utilities could send copies of EIA Form 900 for the net generation data. EIA requires this form to be submitted monthly within 30 days of the end of the reporting month.

Non-utilities could send copies of EIA Form 860B for the fuel use data. EIA requires this form to be submitted annually by April 30th of the following year. Since this is an annual form, the reporting entity would be require to fill in the data on a monthly basis using Form 860B and submit the three monthly forms quarterly.

Non-utilities would have to submit monthly fuel cost information on the modified QFER form because no other agency form collects this information.

Utilities and non-utilities would be responsible for (1) removing superfluous information from the form, if desired, (2) insuring that all required data elements are part of a compliance option, and (3) submitting the data even if in the absence of a compliance option. All non-disclosable data would be kept confidential according to Energy Commission regulations.